EXHIBITS

Analysis of
FERC Order and Staff Report

EXHIBITS

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Exhibit PUC-3

Accuracy of the FERC Staff Estimates of Summer 2000 Supply

Introduction

The FERC staff report concludes that supply and demand conditions throughout the West were tight much of the summer, with emergency conditions concentrated in California.

The CPUC staff disagrees that supply and demand conditions were as tight as the FERC has concluded. This difference of opinion has significant implications for other conclusions about the relative influence of market supply and demand fundamentals, market rules, and market power, the three major factors that the FERC examines in its analysis of high prices in California.

The CPUC staff's primary concern with the FERC analysis is that, due to the limited time available to them to prepare their report, they were able to conduct little of their own data gathering and analysis, instead relying to a large extent on the reports prepared by others regarding Summer 2000 supply conditions. The CPUC staff believe that a more detailed investigation would show that tight supply conditions were caused not just by an unusual confluence of natural events, but by intentional actions of market participants as well.

The FERC staff characterizes Summer 2000 as a period where weather-related demand increases combined with reduced supply due to reduced net imports and higher plant outages to create a very tight supply and demand balance, which created sufficient scarcity to lead to significantly higher market clearing prices. While this scenario may in part explain the <u>outcomes</u> observed last summer, the FERC staff provides little insight into the detailed behavior underlying each of these observations. Indeed, in its discussion of each of the factors behind summer 2000 supply and demand conditions, the FERC readily acknowledges that it does not have a complete picture of these events:

"Higher Demand" After summarizing information provided by the WSCC and the ISO, the FERC staff acknowledges that peak hour demand forecasts for the latter part of the summer in the Cal-ISO area increased only slightly over 1999, and that **actual** hourly peaks fell slightly in 2000. The FERC staff speculates that this observation may in part reflect the response to emergency declarations and actions, but it ignores the implications of its own statement that the peak hour demand forecast and actual hourly peaks were both only "slightly" different from 1999: if this is the case, and higher demand is not as strong an explanatory factor for all hours as so many observers suggest, why were prices so dramatically different? The FERC staff provides no additional analysis on this point.

"Reduced Net Imports" In its discussion of the effect of a reduction in net imports on the supply/demand balance in Summer 2000, the FERC staff mischaracterizes its own data and mistakenly states "The decrease in net imports is generally attributable to increases in exports, not decreases in imports" (Staff Report at 2-17). In fact, the Staff's own data, summarized in Table 2-10 of its report, shows that average hourly imports in 2000 were **below** 1999 levels for every month of the May through August period. This misinterpretation of the data is important, because the FERC staff uses it as a basis to suggest that ISO price caps are the reason that exports increased, and thus are the "cause" for lower net imports.[1] In fact, imports were down compared to 1999 and exports were up compared to 1999, and the FERC has not analyzed this activity in a sufficiently detailed manner to explain this pattern. The table below uses the FERC's data to illustrate that the monthly reductions in imports represented between 40% and 60% of the reduction in "net imports" last summer.

Month	May	June	July	August	May-August
Imports 1999	7,214	7,471	8,784	8,489	7,994
Imports 2000	6,534	6,593	6,807	6,524	6,615
Amount of Change	(680)	(878)	(1,977)	(1,965)	(1,379)
Change (%)	-9%	-12%	-23%	-23%	-17%
Exports 1999	(1,107)	(1,667)	(2,036)	(1,987)	(1,700)
Exports 2000	(1,831)	(2,995)	(3,846)	(4,851)	(3,384)
Amount of Change	724	1,328	1,810	2,864	1,684
Change (%)	65%	80%	89%	144%	99%
Net "loss" to CA 2000 vs. 1999	(1,404)	(2,206)	(3,787)	(4,829)	(3,063)
Share of Loss due to Reduced Imports (%)	48%	40%	52%	41%	45%
Share of Loss due to Increased Exports (%)	52%	60%	48%	59%	55%

This table clearly illustrates that, contrary to the FERC staff's interpretation of the data, imports to California were down significantly in the Summer of 2000, compared to 1999. The reasons behind this should be investigated before the FERC places the blame for lower **net** imports solely on increased exports due to the ISO price caps.

"Increased Plant Outages" As its third explanatory factor for the tight supply and demand conditions in Summer 2000, the FERC staff states that "an increased level of unplanned outages at generating plants is another key factor limiting available generation supply in 2000." While it is simple enough to verify whether a particular unit was

[1] Compared with August of 1999, August 2000 exports averaged 3,136 megawatts above the August 1999 level. This period of increased exports corresponds to the periods in July and August when the price cap in the ISO was reduced from $750 to $500 and then to $250. This correspondence does not necessarily show price caps caused increased exports; however, other things being equal, lower price caps may provide for greater profits from exports if conditions outside California lead to high prices and create greater opportunity costs. (Staff Report at 2-16)

generating or not, the FERC has done little to investigate why any particular units were unavailable at any given time. After suggesting that the reason for higher outages in Summer 2000 is the relative old age of generation plant in California, the FERC undercuts its own explanation by admitting that "it is not clear exactly why these plants went out of service. Detailed analysis of specific causes was not possible for this investigation." (Staff Report at 2-19) Furthermore, the FERC admits that it cannot eliminate the possible explanation that the "unplanned" outages were in fact due to specific owners intentionally taking units out of service in order to create scarcity and drive up prices:

> There are several potential explanations for the increased level of outages.
> There are several potential explanations for the increased level of outages.
> Figure 2-12 indicates a much lower level of planned maintenance in January through April 2000 compared with January through April 1999, so one possibility is that fewer resources are being devoted to planned maintenance. Lack of planned maintenance could be particularly important for older facilities. Given the short duration of outages, the increased number could reflect attempts to fix small problems in preparation for high load conditions. New owners, for example, could be attempting to maximize the availability of their facilities at peak times when the price is high. **A final possibility is just the opposite: owners could be withholding by taking plants out of service at critical times to drive up prices.** The difficulty here is twofold. First, the same general pattern of events permits completely contrary explanations in terms of efficient behavior. Second, specific instances alone may not serve to prove a general pattern, will be hard to substantiate, and cannot be fairly attributed to individual participants without further investigation of these specific cases. (Staff Report at 2-20, emphasis added)

Since the FERC staff acknowledges that further investigation is necessary before concluding that intentional manipulation did not occur, it should not include the higher levels of "unplanned outages" as an explanatory factor in its scenario of "fundamental" factors contributing to the tight supply/demand balance in Summer 2000. As the FERC staff itself acknowledges in the text quoted above, the possibility remains that **market participant behavior** is the explanation for this aspect of supply scarcity this summer, and was therefore artificially created and has nothing to do with market fundamentals. The FERC Staff should conduct further investigation, or enable the CPUC to do so, before absolving the generation owners of any responsibility for the higher plant outages observed in Summer 2000.

Capacity Utilization at the Cal-ISO on August 4

The FERC Staff concludes its analysis of supply scarcity with an examination of a single hour in the California market on August 4, 2000. Beyond the obvious inadequacy of generalizing **any** conclusions from examination of a single hour of data from an extremely complex summer, the CPUC staff also takes issue with some of the specific conclusions drawn by the FERC staff from its examination of this hour.

Table 2-17 of the FERC staff report shows the use of resources by category of resource at hour 16 on August 4. First, the FERC staff notes that the percentage of hydro resources not generating was **26.0 percent**, and the percentage of non-nuclear must take resources not generating was **30.9 percent**. These percentages appear to be quite high, but the FERC staff offers the most innocuous explanation possible:

> "the hydropower resources may be subject to the types of limitations discussed above [e.g., availability of water and environmental restrictions], and the percentages shown are only slightly higher than those in the overall statistics for the West discussed [elsewhere in the Staff report]. Thermal must-take resources include a large number of qualifying facilities, which includes capacity used for other purposes, such as internal uses or steam generation, so these resources may be used for alternate purposes. Discussions with Cal-ISO staff confirmed that these resources are generally limited by the quantity of energy available for bid, rather than by the total physically installed capacity.

Furthermore, the staff's discussion of other resource categories contains another surprising observation, again explained away by the staff:

> For all remaining resources combined (coal, nuclear, and other thermal categories,) only 2.7 percent were not scheduled or bid. One category where the owner of the facility has the discretion to bid or schedule the unit without bidding, the "Other Thermal (excluding RMR)" category, shows a higher percentage unscheduled or not bid than others, 8.6 percent. **This quantity may represent owners holding back capacity to use if other scheduled units have outages, but it is not clear whether this is the reason or not.** In any case, this quantity is a small amount of the total capacity neither scheduled nor bid, and does not suggest a large amount of withholding, regardless of the intent underlying the failure to schedule the capacity.

Finally, the FERC staff concludes its examination of August 4 as follows:

> For the peak hour shown in Table 2-17, there does not appear to be a significant concern about resources not used. **It is possible that resources are fully used at peak times when prices are high, but resources that are economic at other times are held off the market in**

> **an attempt to drive up prices. Further work would be necessary to study other hours to examine whether patterns vary at other times. This work could not be conducted within the time frame of the present investigation.**

The CPUC staff is concerned that the FERC staff admits to not really knowing why plants were not operating, but ignores this doubt when agreeing with other market observers that supplies were tight because units were out, and suggesting that this is a reasonable explanation without examining the reasons for these outages.

Exhibit PUC-4
Plant Availability – Pre and Post Divestiture

The FERC Staff Study states, " Supply and demand conditions throughout the West were tight much of the summer[1]". The report went on to say that many broad factors contributed to the emergency conditions experienced in California. Outages increased significantly questioning plant availability during peak demand time.

	Total Outage	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug
2000	Retained	0	0	0	120	172	221	155	254
	Divested	5073	4241	4951	7144	4861	3816	3550	3861
	Total	5073	4241	4951	7264	5033	4037	3705	4115
1999	Retained	0	0	0	0	242	272	307	218
	Divested	4946	6748	8241	10282	4996	2126	1557	972
	Total	4946	6748	8241	10282	5238	2398	1864	1190
1996	Retained	2483	2482	2482	2482	2483	2483	2483	2483
	Divested	465	569	612	590	634	828	824	625
	Total	2948	3051	3094	3072	3117	3311	3307	3108

The table above compares the total outages recorded for the 8-month period of Jan-Aug for the years 1996[2], 1999 and 2000. On average, outages were lower in 1996 than in 1999 and 2000. Taking a simple 8-month average, total outages for all three years were 3126 MW, 5113 Mw and 4802 MW respectively.

Prior to deregulation, generation plants were owned and operated by the incumbent utilities. Total outages are consistent throughout the first 8 months of 1996. In analyzing the outage reasons, the majority of outages were for regular scheduled maintenance.

Under economic regulation the utilities operated their plants in conjunction with power purchases to minimize their portfolio costs. They could afford to not operate an uneconomic plant when there were cheaper alternatives because their depreciation, operating costs and cost of capital were all recovered in base rates and were collected under a balancing accounts, the electric Revenue Adjustment Mechanism (ERAM), which assured their full recovery of the authorized revenue requirements. After restructure, the utilities recovered their costs through the CPUC adopted cost recovery mechanisms mandated by AB 1890. Costs were recovered wither as transition costs for uneconomic plants where their costs exceeded the revenues from the IOS/PX markets or as economic plants where their profitable operations contribute towards other stranded cost recovery. The new owners of divested plants could only recover their costs through the operation of their plants in the wholesale or retail markets. If they do not operate there is no revenue. The only possible way to profit from not operating a plant is if the withholding of production results in a much higher market clearing price for other units owned by the same operator or by receiving higher than market prices when the withheld unit is called in an "out-of-market" transaction by the ISO.

[1] Staff Study to the Federal Energy Regulatory Commission on Western Markets and the Causes of the Summer 2000 Price Abnormalities pg. 2-1.
[2] 1996 data is incomplete as we are waiting the arrival of PG&E's data for retained units.

The data shows that after the incumbent utilities divested their generation plants, outages increased significantly. The FERC Staff Study states, "California has a number of gas fired plants representing 36% of generation capacity. These steam plants are old and prone to outages; 82% of these plants are over 30 years old, and 37% are over 40 years old[3]". Upon further review, the FERC concluded that there were no abnormalities in the reason for the outages.

While there is no question that much of California's thermal generation is old, the increased outage levels demonstrated by the table above are significant enough to raise questions as to whether they are adequately explained by age alone. The plants were old but reliable in 1996. It is presumptive t o conclude without further investigation that they were so much older only a few years later that their reliability declined to this extent. We would expect, for instance, that the new owners are running these plants with the goal of maximizing profits rather than ensuring reliability and steady output, as was the case under the regulated business model. The table above shows outages in the early part of the year were higher in 1999 than in 2000. If, as the FERC hypothesized, as a plant gets older more outages and of longer duration are expected, there should have been an increase in outages for 2000. Outages increased during the summer months, which raises concerns.

It remains unclear, however, whether the decline in availability is due to increased age, bad luck, poor operational practices, reduced maintenance, or strategic withholding to increase revenues from commonly owned units. What is clear is that the outage data raises enough questions to warrant further investigation. Among the data subpoenaed from California generators is information sought by the CPUC in its November 6 Motion to Compel. Without this information, validity of the outages cannot be ascertained.

[3] Staff Study to the Federal Energy Regulatory Commission on Western Markets and the Causes of the Summer 2000 Price Abnormalities pg. 2-19.

Exhibit PUC-5
Unit Availability on Stage II Emergency Days, Summer 2000

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Exhibit PUC-6
Marginal Cost Baseline and Excess Cost Calculation

Section 3-B-1 of the FERC's November 1, 2000 staff report asserts that one reason for the higher electricity prices in the West during the summer of 2000 was a significant increase in input costs rather than market malfunction. According to FERC's staff, "… market clearing prices that approach $250/MWh price cap may simply reflect the true cost of the resource and be solely the result of tight supply, not the exercise of market power." (See FERC Staff Report at p. 3-21.) FERC's staff specifically attributes increases in natural gas prices and NOx compliance costs for higher market clearing prices. However, the CPUC Staff's analysis reveals that while these production costs did increase significantly during the summer of 2000, these costs can account for only about 40% of the total increase in PX energy costs during the summer of 2000 relative to the summer of 1999. The CPUC Staff's analysis also demonstrates that PX day-ahead revenues during the months of June through September of 2000 exceeded baseline marginal costs, adjusted for increases in natural gas and NOx prices, by nearly $4.3 billion. See Table 5-1.

Table PUC-6-1

Calculation of Excess Revenues
California Power Exchange Day-Ahead Market

Month	Actual PX Revenue 1999	Actual PX Revenue 2000	Imputed PX Cost 2000	Excess PX Cost 2000
Jun	$406,845,758	$2,279,575,728	$886,163,550	$1,393,412,179
Jul	$597,044,478	$2,104,016,551	$1,161,899,838	$942,116,713
Aug	$666,821,424	$3,115,881,377	$1,480,222,234	$1,635,659,143
Sep	$601,936,026	$1,963,375,322	$1,646,460,970	$316,914,353
Total	$2,272,647,687	$9,462,848,979	$5,174,746,591	$4,288,102,387

Revenue Increase during Summer 2000 Due to Fuel and NOx Costs	$2,902,098,905
Percent Increase due to Fuel and NOx Costs	40.4%
Total Revenue Increase during Summer of 2000	$7,190,201,292
Percent Revenue Increase during Summer of 2000	316.4%

Notes:

1. Total Revenue = $^{730}\mathrm{SUM}_{i=1}$(Unconstrained Day Ahead Price$_i$ * Demand$_i$)
2. Imputed Revenue = Adj Marginal Costs * Volume

Based on recorded data from June through September of 1999, the CPUC Staff established baseline marginal costs. To establish baseline marginal costs, the CPUC Staff started with PX day-ahead energy costs for each of the summer months in 1999. The CPUC Staff assumed that market participants would not bid less than their marginal cost, making actual revenues for summer 1999 a conservative estimate of marginal cost at that time if one were to divide total monthly PX energy costs by total monthly electric sales volumes. CPUC Staff calculated PX energy costs by multiplying hourly unconstrained day-ahead PX clearing price by hourly electric demands. We assume that California's electricity market functioned reasonably well during the summer of 1999 and that these PX prices represent reasonable marginal cost levels for the incremental generating unit in each hour. We also assume that if we adjust the marginal cost baseline by all known changes in production costs that occurred during the summer of 2000 relative to the summer of 1999, that the adjusted baseline represents reasonable marginal costs for the summer of 2000. Furthermore, these calculations provide a simplified way to demonstrate that the market-clearing price failed during the summer of 2000. Table 5-2 shows the average baseline marginal costs for June through September 1999.

Table PUC-6-2

Marginal Cost Baseline
Summer of 1999

	1999 Recorded Data (Baseline)		
Month	Total Revenue ($)	Total Volume (MWh)	Marginal Cost ($/MWh)
Jun	$406,845,758	15,792,596	$25.76
Jul	$597,044,478	18,941,466	$31.52
Aug	$666,821,424	19,212,069	$34.71
Sep	$601,936,026	17,122,621	$35.15
Total	$2,272,647,687	71,068,751	$31.98

Notes:
1. Total Revenue = $^{730}\mathrm{SUM}_{i=1}$(Unconstrained Day Ahead Price$_i$ * Demand$_i$)

An important consideration to note is that volumes traded through the PX day-ahead market actually declined by about 2% during the summer of 2000 relative to the summer of 1999. At the same time, PX energy costs increased by 316%. Table 5-3 shows the change in electric sales volumes for each month.

Table PUC-6-3 Electric Sales Volumes 1999 Versus 2000			
Month	1999 Volume (MWh)	2000 Volume (MWh)	Percent Change in Volume
Jun	15,792,596	17,219,831	9.04%
Jul	18,941,466	18,245,771	-3.67%
Aug	19,212,069	17,782,911	-7.44%
Sep	17,122,621	16,413,002	-4.14%
Total	71,068,751	69,661,515	-1.98%

The CPUC staff also adjusted the baseline marginal cost to reflect increases in natural gas prices. During the summer of 1999, natural gas prices remained relatively stable, ranging from a low of $2.70 per MMBtu in June of 1999 to a high of $3.06 per MMBtu in September of 1999. However, during the summer of 2000 natural gas prices ranged from a low of $4.84 per MMBtu in July to a high of $6.3200 per MMBtu in September. Table 5-4 shows our fuel costs adjustment to the baseline marginal cost.

Table PUC-6-4 Fuel Cost Adjustment To Marginal Cost Baseline				
	1999 Price ($/MMBtu)	2000 Price ($/MMBtu)	Adjusted Price ($/MMBtu)	% Change
Jun	$2.70	$4.99	$22.90	84.8%
Jul	$2.76	$4.84	$20.80	75.4%
Aug	$3.06	$5.45	$23.90	78.1%
Sep	$3.06	$6.32	$32.60	106.5%

Assumptions
1. Heat Rate = 10,000 Btu/kWh

Finally, we adjusted the baseline marginal cost by increases in emission costs that occurred during the summer of 2000. During the summer of 1999, NOx emission costs ranged from $7.20 per MWh in June to $12.44 per MWh in September. During the summer of 2000, NOx emission costs ranged from $10.00 per MWh in June to $45.00 per MWh in September. Table 5-5 shows our NOx costs adjustment to the baseline marginal cost. Table 5-6 shows all adjustments and the resulting adjusted marginal cost baseline for the summer of 2000.

Table PUC-6-5

NOx Cost Adjustment
To Marginal Cost Baseline

	1999 Price ($/MWh)	2000 Price ($/MWh)	Adjusted Cost ($/MWh)	% Change
Jun	$7.20	$10.00	$2.80	38.9%
Jul	$8.64	$20.00	$11.36	131.5%
Aug	$10.37	$35.00	$24.63	237.5%
Sep	$12.44	$45.00	$32.56	261.7%

Table PUC-6-6

Summary of Adjustments to Marginal Cost Baseline
($/MWh)

	Marginal Cost	Adjustments		Adj Marginal Cost
Month	1999	Fuel Cost	NOx Cost	2000
Jun	$25.76	$22.90	$2.80	$51.46
Jul	$31.52	$20.80	$11.36	$63.68
Aug	$34.71	$23.90	$24.63	$83.24
Sep	$35.15	$32.60	$32.56	$100.31

As shown in Table 5-6, marginal costs increased from about 60% to 160% between the summer of 1999 and the summer of 2000 as a result of increased production costs. While these increases in production costs that occurred in 2000 represent significant increases relative to 1999, they come nowhere near explaining the 316% increase in PX energy costs that California has observed between the summers of 1999 and 2000.

Exhibit PUC-7
Correlation Between Loads and Prices

The November 1, 2000 report of the FERC staff asserts that scarcity of power supply in the West, particularly in California, during the summer of 2000 produced high energy prices. However, the CPUC Staff's analysis of actual hourly ISO loads and total prices[1] during the first six months of 2000 reveals that little or no correlation exists between high loads and high prices

The CPUC staff calculated the correlation between load and price for all hours from January 1, 2000 through June 30, 2000. (See Exhibit PUC-7-1) This correlation (R^2) reveals that loads are responsible for only about 29% of the variation in price. This correlation of 29% suggests that factors other than increases in demand causes prices to spike during 2000.

As shown in Exhibit PUC-7-1, the variation in total price becomes significantly greater between 30,000 and 35,000 MW. Therefore, the CPUC staff calculated correlations between loads and prices for loads less than 30,000 MW and for loads greater than 30,000 MW for the January 1, 2000 through June 30, 2000 period. Exhibit PUC-7-2 plots the data for loads less than 30,000 MW and Exhibit PUC-7-3 plots the data for loads greater than 30,000 MW. Exhibit PUC-7-2 shows that when loads were less than 30,000 MW, increasing generation demand was responsible for only about 24% of the increase in energy prices. In the same way, Exhibit PUC-7-3 shows that when loads were greater than 30,000 MW, increasing demand was responsible for about 58% of the increase in energy prices. These results suggest that factors other than demand played a significant role in the energy price spikes that occurred in California during the summer of 2000. These results are not surprising given the relative inelasticity of energy consumption, especially among smaller customers. Table PUC-7-1 below summarizes the results of CPUC Staff's analysis.

Table 7-1

	Figure 7-1	Figure 7-2	Figure 7-3
Load	All Loads	< 30,000 MW	> 30,000 MW
Coefficient of Regression	0.0099661	0.0014904	0.043323
Correlation (R^2)	0.29	0.24	0.58

Finally, it is also worth noting that the FERC's staff report notes that the generation shortage in the west began long before the summer of 2000. However, California did not experience high prices prior to the summer of 2000. Based on these facts and its analysis of load and price data, the CPUC Staff concludes that the high prices during the summer of 2000 were produced primarily from factors other than supply shortage.

[1] The total price used in this analysis is the PX price plus the ISO ancillary services.

Figure 7-1
Correlation Between Loads and Price
January thru June 2000
All Loads

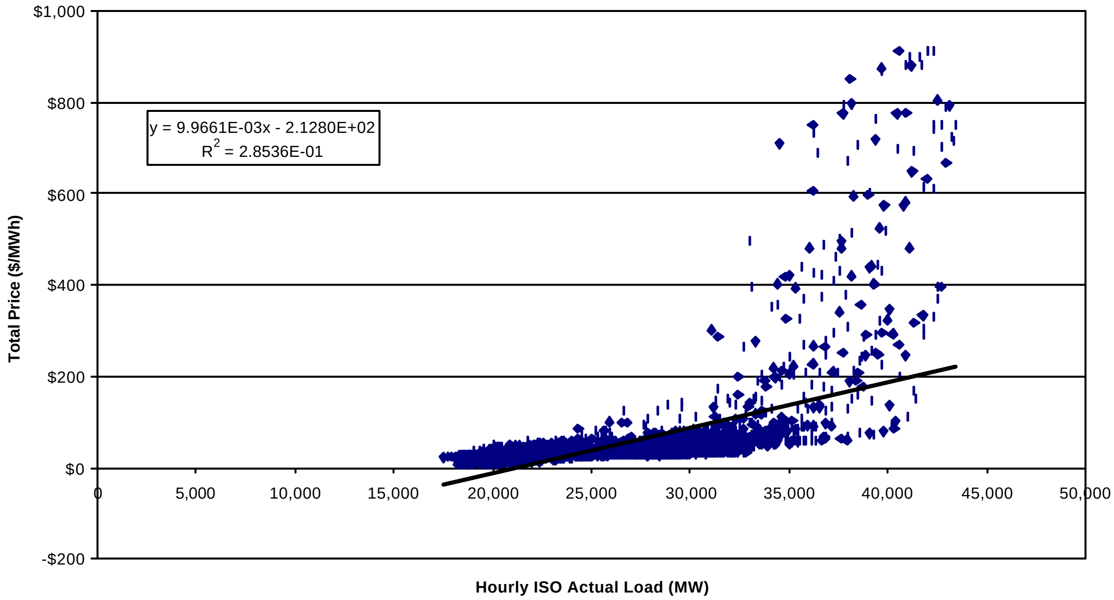

Figure 7-2
Correlation Between Loads and Price
January thru June 2000
Loads < 30000 MW

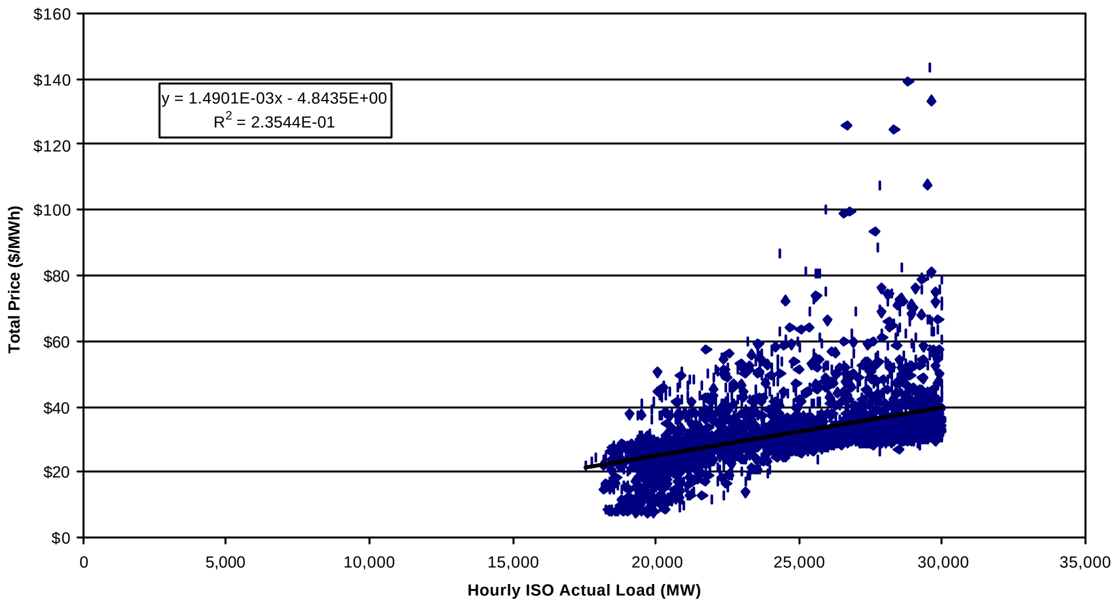

Figure 7-3
Correlation Between Loads and Price
January thru June 2000
Loads > 30000 MW

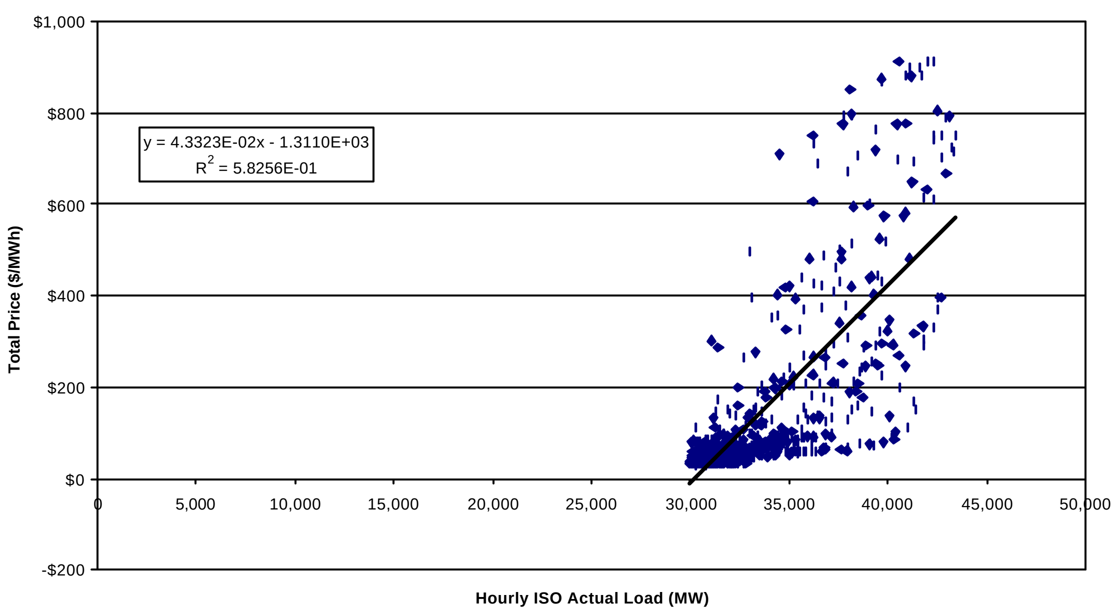

Exhibit PUC-8
Import/Export Patterns Need Further Investigation

The FERC Staff Report concludes that "(E)xports increased significantly, with little overall change in the level of imports."[1] At first glance, this seems implausible. Although lower overall than 1999, scheduled imports remained virtually unchanged throughout the summer of 2000 even though temperature and load conditions in adjacent states led to higher demand in those states, and presumably less power available for export to California. In addition, hydroelectric conditions in the Pacific Northwest led to lower than normal imports of hydropower.

If there is less power available from outside the state, then what accounts for the fact that imports stayed the same? The Commission cannot know the precise answer to this question without undertaking a more detailed investigation of market behavior. It is possible that some of the "exported" power ultimately served needs in California and was classified as "import". We do know that exports and Out-of-Market calls increased as the summer progressed. By the end of June, market participants understood that supplies were tight and that the ISO was consistently forced to meet demand in the real time market or via Out-of-Market purchases.

Prior reports have acknowledged the existence of incentives for generators to manipulate the system using exports. A report issued by the California Power Exchange's Compliance Unit, asserts: "(U)ncapped Out-of-Market calls provide an incentive to generators in California to export their Day-Ahead supply for use in the Out-of-Market purchases."[2] The report goes on to say that generators have the incentive to schedule exports of power through contracts with out of state entities (possibly affiliates), "park" the power in surrounding control areas, and then resell the power at a higher price into California as Out-of-Market power, thus avoiding price caps.[3]

The ISO's Department of Market Analysis posits: "If in-state generators know that a better deal can be had from out-of-market purchases than from participating in the ISO's market, then we would expect them to export their power to out-of-state control areas and reduce their participation in the ISO's markets, thereby exacerbating the need for *out-of-market* purchases under tight supply/demand conditions."[4]

This behavior has two detrimental effects. First, by removing supply from the day-ahead and hour-ahead markets through forward contracting to export power out of state and forcing the ISO to procure supplies in real time, the perpetrators of this behavior contribute to the high incidence of emergency alerts and threaten the reliability of the system. Second, exporting power with the reasonable expectation that the power will be

[1] FERC, "Staff Report to the Federal Energy Regulatory Commission on Western Markets and the Causes of the Summer 2000 Price Abnormalities: Staff Report on U.S. Bulk Power Markets", November 1,2000, page 1-2.

[2] California Power Exchange Corporation, "Price Movements in California Electricity Markets, Analysis of Price Activity: May-July 2000", September 29,2000, page 5.

[3] Ibid., page 38.

[4] California Independent System Operator, Department of Market Analysis, "Report on California Energy Market Issues and Performance: May-June, 2000", August 10,2000, page 3.

sold back into California in real time or as an Out-of-Market call, amounts to withholding with the intention to drive up prices, especially if the contract is with an affiliated entity.

The FERC Staff Report acknowledges that several generators reported forward contracting large portions of their supply outside of California and that the buyers may have resold the power back into California.[5] The report further states that a marketer purchased supply from California generators before the summer and then resold it into California as replacement reserves during emergency conditions.[6] The report goes on to say these types of exporting practices are not really gaming since "…there are no administrative rules on the amount of capacity that must be provided to meet load…."[7] Since this is permitted under the rules, it is "…not necessarily a market power problem" and only "…becomes a problem if it is associated with a pattern of withholding resources from the market in order to drive up prices."[8] Given the experience of this past summer, this situation warrants a full investigation.

Higher Demand in the West

Load growth and higher-than-normal temperatures contributed to higher demand for power throughout the West. Demand has been growing steadily in the West, particularly in technology driven economies such as the Northwest and California. Higher demand for power in states adjacent to California means these areas have less excess generation to sell into California after serving their native load.

Total energy consumption for states in the WSCC, excluding California, increased by 4.7% in May over 1999, and increased by 7.3% in June over the same period in 1999. According to the FERC Staff Report, residential energy consumption for May in Arizona, New Mexico and Nevada increased by 36.3%, 5.0% and 34.8%, respectively, over 1999. In June, these same states experienced increases in residential energy consumption of 22.3%, 11.0% and 27.2%, respectively, over June of 1999.[9]

The increase in demand throughout the West in summer of 2000 is driven, to a significant degree by higher-than-normal-temperatures. According to the National Oceanic and Atmospheric Administration (NOAA), the summer of 2000 ranks as one of the ten hottest summers on record in the West.[10]

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[5] FERC, "Staff Report to the Federal Energy Regulatory Commission on Western Markets and the Causes of the Summer 2000 Price Abnormalities: Staff Report on U.S. Bulk Power Markets", November 1,2000, page 5-15.
[6] Ibid., page 5-15.
[7] Ibid.,page 5-15.
[8] Ibid., page 5-15.
[9]FERC, "Staff Report to the Federal Energy Regulatory Commission on Western Markets and the Causes of the Summer 2000 Price Abnormalities: Staff Report on U.S. Bulk Power Markets", November 1,2000, page 5-5.
[10] California Power Exchange Corporation, "Price Movements in California Electricity Markets, Analysis of Price Activity: May-July 2000", September 29,2000, page 20.

Given these conditions, it is likely that adjacent states and power producers would not be increasing exports of power to California, but would be serving their native load, and may even be looking to import power from California. This possibility should be investigated further in order to fully understand the conditions in adjacent areas, and how these conditions impact the ability of neighboring jurisdictions to supply import power to California.

Lower Hydro Imports from the Pacific Northwest

Hydro conditions were worse this summer than last, resulting in a 32% reduction from 1999 levels of scheduled imports from the Pacific Northwest for June (from 4930 MW in 1999 to 3348 MW in 2000).[11] The FERC Staff Report states that hydro generation from outside California was 8.6% below 1999 levels in May 2000 and 23.2% below 1999 levels in June 2000.[12] Higher than normal temperatures in the PNW and lower runoff meant that the PNW had less excess power to export to California.

Serious Questions Raised By These Conditions and Prior Reports

Given the conditions discussed above, where is the power coming from to maintain the same level of imports? In the absence of a clear explanation, it is reasonable to assume that some portion of the increased exports is coming back into California as Out-of-Market power purchases or in the replacement reserves market. This seems to be one clear way that the same level of imports could be maintained while California's traditional sources of import power are either decreasing, as with hydro, or are being used to serve native load, which has increased due to load growth and high temperatures.

The possibility of the exercise of market power with respect to exporting power as a form of withholding, and then selling back into the state at prices substantially higher than marginal cost, must be closely examined. Such behavior significantly harms consumers by raising prices without providing any more generation than would have been available without this type of market manipulation.

Further Investigation Needed

Examination of *scheduled* imports and exports alone, will not capture the activities of generators and marketers who may be engaging in these types of transactions. The actual, or *metered*, imports and exports should be examined to determine the actual energy flows at the interties. This would yield a more precise picture of the actual quantities that flowed in and out of California.
Once the actual flows have been established, financial contracts and transactions of in-state generators, scheduling coordinators and marketers should be examined to determine

[11] California Independent System Operator, Department of Market Analysis, "Report on California Energy Market Issues and Performance: May-June, 2000", August 10,2000, page 41.
[12] FERC, "Staff Report to the Federal Energy Regulatory Commission on Western Markets and the Causes of the Summer 2000 Price Abnormalities: Staff Report on U.S. Bulk Power Markets", November 1,2000, page 5-6.

who shepherded the power out of state and, potentially, back into California. This aspect is very important since this is the only record of what happened outside of the California ISO and PX. ISO and PX import and export information will show flows out of the state and back in when it reappears in the real time markets or as Out-of-Markets calls, but only careful examination of the financial transaction trail will yield clues as to who may be manipulating this aspect of the market.

In the section on "Market Power", the FERC staff states: "there is evidence suggesting that sellers had the potential to exercise market power during this past summer….(H)owever, the *evidence available and analyzed* during this investigation, to evaluate whether there were *actual* exercises of market power, is inconclusive."[13](emphasis added) It does not appear that the FERC examined generator, marketer and scheduling coordinator power transaction data, or import and export transaction data from adjacent control areas. The FERC Staff Report acknowledges that because of the expedited basis of the study, staff was not able address all of these issues in depth and that the intent of the report is to provide "the big picture".[14]

Without further study, the FERC cannot be certain that such conduct did not occur in the summer of 2000. Given the current state of our knowledge about market behavior, particularly as it pertains to these export and import transactions, it would be dangerous to alter existing price protections. Any action that increases consumer vulnerability to such price manipulation, is detrimental to the individuals as well as to the health of the economy as a whole.

The CPUC respectfully submits that generator, marketer and scheduling coordinator contract transactions; import and export activities with adjacent control areas; and actual *metered* energy flows at the interties must be thoroughly examined. The anomalies of the import and export transactions must be fully investigated before any meaningful reforms can be implemented. The CPUC issued subpoenas which request specific information on transactions outside of the PX and ISO markets. This information may allow decisionmakers to trace the paper trail of power transactions, detect patterns of behavior and craft reform proposals to address any unwanted behavior in a targeted way. Until we fully understand what is happening *in practice*, it is unwise to implement untried reforms that may only work *in theory*.

[13] Ibid., page 5-16.
[14] Ibid., page 1-4.

Exhibit PUC-9
Market Power Behavior

In the *Staff Report to the Federal Energy Regulatory Commission on Western Markets and the Causes of the Summer 2000 Price Abnormalities*, FERC Staff finds "…evidence suggesting that sellers had the potential to exercise market power during this past summer. However, the evidence available and analyzed during this investigation, to evaluate whether there were actual exercises of market power, is inconclusive." (p. 5-16) (Emphasis added.) The report notes that further study is needed to substantiate a finding of market power abuse. In support of this conclusion, FERC staff points to a number of complicating factors, including: (1) that it is difficult to separately identify the economic effects on market clearing price (MCP) of scarce supply coupled with low demand responsiveness versus market power; (2) that it is difficult to distinguish physical withholding from real unit outages occurring during periods of high demand; and (3) that is it is difficult to discern the effect on MCP of suppliers and buyers underscheduling load and supply in the day-ahead market and then shifting volumes to the real-time market.

Notwithstanding the absence of a finding of market power, the report states that "… at least some of the June price spikes appear to be attributable to market power, and high bids observed in PX and replacement reserve markets during this investigation provide further indications that above marginal costs can be sustainable." (p. 5-22) Department of Justice (DOJ) guidelines define market power as "the ability profitably to maintain prices above competitive levels for a significant period of time."[1] Given that the market conditions described in the staff report largely reflect the DOJ's criteria of market power (i.e, MCP exceeding marginal costs on a sustained basis) and that the evidence reviewed by FERC staff strongly suggests actual market power behavior by participants, the CPUC has serious reservations with regard to the efficacy of the FERC-proposed market reforms (including the $150/MWh soft cap) to protect consumers from continued market power abuse. In the absence of a clear finding by FERC staff that market power does not exist, FERC should not so readily presume that the California market will function well under its proposed framework.

Based on modeling results conducted for the CPUC as part of its review of PG&E's proposed hydropower asset divestiture, the CPUC is aware of several withholding scenarios under which certain suppliers could possibly exercise undue influence on MCP. The *Initial Market Power Analysis of PG&E Hydro Post-Divestiture Operations* report, prepared by LCG Consulting, modeled two simple strategies of withholding thermal generating capacity. Overall, the study finds that under certain situations, simply withholding gas-fired peaking generation can increase the MCP and result in market power, provided that the plant owner also owns sufficient inframarginal cost generation from which to make up for the lost profits of not running the withheld unit(s). Generation ownership portfolios exist in California that strongly resemble the generation

[1] U.S. Department of Justice and Federal Trade Commission, *Horizontal Merger Guidelines*, Issued April 2, 1992 and revised April 8, 1997.

portfolio's modeled in the study found to be capable of exercising market power. Such portfolios need not include hydro assets for these strategies to be effective

Under the first strategy, four gas-fired units, representing about 2200 MW of a larger capacity portfolio, were assumed to be made unavailable for a full month (i.e., placed on outage). In this scenario, the 2200 MW which would typically be called on during the peak and shoulder peak hours are withheld while the generating owner's remaining units in the portfolio (assumed to amount to at least 60 percent of withheld capacity) are bid at marginal cost. The withheld generation represents the highest marginal cost units of the owner's portfolio. Based on the modeling results, the report finds that when combined with substantial ownership of inframarginal cost units, especially low-cost hydro storage facilities, this withholding strategy can drive up the MCP beyond otherwise competitive levels and produce profits in excess of the profits that would occur had the peaking units not been withheld. In this case, the MCP paid to the inframarginal units outweighs the revenue loss of not running the highest marginal cost units (i.e., the peakers placed on outage). Additionally, the modeling shows that as the proportion of inframarginal generation capacity increases in relation to the peaking units held off-line, even higher profits accrue to the portfolio owner.

Under a second, more focussed strategy, a gas-fired peaking unit is assumed to decrease its output by 30 MW in selected hours in a summer month. The unit selected in the model represents one percent of the plant owner's generation portfolio. As a result of the withholding, the MCP increased during certain hours thereby increasing profits for the plant owner's remaining portfolio. As in the first case, the increased MCP paid to the remaining generation exceeds the revenue loss from the 30 MW curtailment..

The thermal generation withholding strategies examined in the report are very simplistic and were designed for purposes of conducting screening tests at the front-end of a market power study. Given that these screening tests affirm the opportunity for plant owners to exercise market power, it is likely that more refined withholding strategies may be found to extract even higher profits than those described in the report. The modeling results point to the need to test for these more refined and focussed withholding strategies that could be employed by savvy, well-informed market participants. In light of the study's modeling results and the lack of a clear finding articulated by FERC staff in its report that market power behavior is not taking place in the California market, the CPUC questions whether the proposed market reforms are on target for mitigating possible continued market power abuses.

Beyond the issue of ownership of certain generation portfolios for market power purposes, the ability to influence MCP rests, in part, on securing access to information concerning the relevant marketplace. It is the CPUC's contention that the western electric power industry does not reflect an industry culture where market intelligence data is both equally coveted and guarded. Instead, it appears that today's industry culture in California remains marked by patterns of open communication more typical of a regulated industry, but inappropriate in a competitive market.

Beginning with the establishment of the Western Systems Coordinating Council (WSCC) in 1967, participants in bulk power markets in the Western Interconnection have helped shape an industry environment characterized by coordinated action and open communication. Such efforts are evidenced by the development of an Unscheduled Flow Mitigation Plan, development of a Reliability Management System, the formation of numerous committees involving industry participants meeting on a regular or periodic basis,[2] and the establishment of data reporting requirements. While the safe, reliable, and efficient operation of the region's interconnected high-voltage transmission system is predicated on achieving a high level of coordination among a broad cross section of industry participants, it is possible that market participants can take advantage of such coordination. For example, WSCC's Electric High Voltage (EHV) database, which until recently contained California system data showing hourly generator plant output and hourly transmission path loading information, was made available for download by WSCC members. As a WSCC employee acknowledged, such information could be used to game the market.[3]

This culture of open communication has evolved over the last several decades and exists not only at the system operations level for reliability purposes, but also within the context of competitive wholesale energy markets. Federal legislation, particularly the Public Utility Regulatory Policies Act of 1978 and the Energy Policy Act of 1992 (EPACT), expanded the number and types of entities participating in wholesale markets by introducing new categories of non-utility generators (with mandatory purchases of QF power by utilities) and requiring transmission-owning utilities to provide open access to transmission. Many of these transactions were based on standard contracts which often were developed through collaborative processes. With enactment of PURPA and EPACT, a robust wholesale market for electricity has flourished in the western grid involving a multitude of utilities and non-utility generators executing transactions at avoided costs rather than competitive rates.

Along with the introduction of non-utility generators and power marketers in wholesale markets came the need for these entities to form trade associations. The trade associations allow members to share information, to network, and to have their views on issues of common concern conveyed to legislative and regulatory bodies. Among these organizations which have been established over the years are the Power Marketing Association, the Western Power Trading Forum, the Cogeneration Association of California, the Independent Energy Producers Association, the California Cogeneration Council, the Power Association of Northern California, and the National Independent Energy Producers association.

[2] Examples of such committees and work groups include: Security Coordination Subcommittee, Joint Guidance Committee, System Review Work Group, Interchange Scheduling and Accounting Subcommittee, Dispatcher Training Subcommittee, Operating Transfer Capability Policy Group, Executive Policy Issues Task Force, Data Exchange Work Group, Operating Issues Work Group, Reliability Subcommittee, Technical Studies Work Group, Unscheduled Flow Administrative Subcommittee, Information Management Subcommittee, Compliance Monitoring and Operating Practices Subcommittee

[3] "California Power Companies May Have Used ISO Data to Increase Prices," Dow Jones Business News, October 20, 2000.

Additionally, it should be pointed out that with the proliferation of non-utility generators and power marketers, and the inception of the ISO and PX, there has been substantial movement of personnel among market participants in the region. Some of these personnel have many years experience working in the western electricity industry and possess vast knowledge of historic energy trading practices and electricity production information. Aside from current FERC and CPUC restrictions governing communications among employees from various business units within a regulated utility and between utilities and their unregulated affiliates, the CPUC is not aware of standard protocols or employee code of conduct manuals for non-regulated entities that limit inappropriate communications among participants.

There exists an absence of evidence indicating that patterns of communication among participants in the western power industry have evolved in a manner appropriate for a functionally competitive market. Without evidence to the contrary, the CPUC is concerned that market intelligence information will continue to be shared or otherwise disseminated in a manner reminiscent of a regulated industry versus a competitive marketplace where such information would ordinarily be vigorously guarded.

Exhibit PUC-10

Estimate of Impact of Load Differentiated Price Caps on PX Charges for Summer 2000

The purpose of this exhibit is to develop a rough estimate of how the ISO's proposed Load-Differentiated Caps on the market clearing price would have affected total electric revenues in the PX day-ahead market this past summer, all other things being equal

Load-Differentiated Caps reflect an effort to more closely provide the proper ceilings to the off-peak hours when "opportunity costs" were driving prices to reach the ISO's caps. The intent is to place a ceiling on the prices so they more closely reflect true operating costs. The calculation of the revenue savings is compared to the revenues expending during the summer as reflected by the PX prices and the PX quantities. Although the caps, as approved by the ISO, would apply directly only to bids received by the ISO, we are assuming that such caps would have served to control prices in the PX, as well. This has been the observed effect with past caps, since purchasers would not buy power through the PX when it could be purchased for less at the ISO.

We applied the hourly PX unconstrained market clearing price (UMPC) to the individual PX Day Ahead Scheduled Loads to derive the total PX revenues for June 1 through September 30, 2000. The estimated marginal cost reflects more accurate operating costs which incorporate an increase in NOx emissions and gas prices that occurred through the summer of 2000. For a more detailed explanation, see Exhibit PUC-7.

We assumed that market participants' behavior remained unchanged during the summer, i.e. the pattern of bidding into the PX and ISO remained unchanged and the load-differentiated cap was overlayed onto the existing PX loads. Further, we assumed a gas price of $6/mmBTU ($5.50 plus 50¢ transportation charge). We applied the new Load-Differentiated Caps to the hourly PX demand. The calculation of the caps is as follows:

Table 1
Calculation of Price Caps

ISO Two Day-Ahead Load Forecast (MW)	Heat Rate	Cap ($/MWh)
Below 24,999	10775	65
25,000 – 29,999	14175	85
30,000 – 34,999	17225	105
35,000 – 39,000	27225	165
40,000 & Above	$250/MWh cap	250

The result are listed in the table below. The total PX costs have been reduced to reflect the charges above marginal costs, while taking into account the increases in NOx emissions and gas prices that occurred during the summer. The actual cost in the Total PX Costs column represent the costs that might have been expected under a competitive environment. The ISO's Load-Differentiated Caps turns out to be a modest proposal that would not have protected consumers from all of the excessive charges imposed by market participants this past summer. However, it would have encouraged market participants to bid at levels closer to true marginal costs, especially during off-peak periods.

Comparison of Charges Under the Load-Differentiated Cap
To Actual PX Charges for June – September, 2000
($000)

	PX	Load Differentiated Caps
What Consumers Paid	$ 9,462,849	$ 9,462,849
Estimated Caps Savings	—	$ 1,837,967
Remaining Costs	$ 9,462,849	$ 7,624,882
Estimated Marginal Costs	$ 5,174,747	$ 5,174,747
Costs in Excess of Estimated Marginal Costs	$ 4,288,102	$ 2,450,135

Exhibit PUC-11
Recent Regulatory History of Forward Power Purchases by Utilities

The CPUC has consistently supported and facilitated forward power purchases by the utilities. Beginning in July of 1999, the utilities were authorized to purchase forward power contracts through the California Power Exchange's Block Forward Market. Beginning in August of 2000, the CPUC has allowed the utilities to purchase contracts for forward power outside of the PX as well.

Preferred Policy Decision:

The CPUC's policy for forward power purchases is integrally related to the "buy/sell requirement." In the Preferred Policy Decision (D.95-12-063) the CPUC mandated that during the transition period the three IOUs bid all of their generation into the California Power Exchange (PX) and procure electric power only from the PX. (Ordering Paragraph 5) This has become known as the "buy-sell requirement".

The PX was favored as the sole source of the IOUs' electric power, in order: (1) to facilitate the calculation of the energy credit for purposes of amortizing stranded costs; (2) to ensure that energy procured would be competitively priced and not subject to market power; and (3) to increase the depth of the PX market. (Finding of Fact 12)

The PX's Block Forward Market:

When it first began operation, the PX's two markets were the day-ahead market and the hour-ahead market. On March 23, 1999, the PX applied to the FERC to establish a 6x16 Block-Forward Market (BFM), to be operated by its California PX Trading Services (CTS) division. Trading lots were to be of 1 MW and 25 MW. As an intervenor in the proceeding, the CPUC recommended approval of the application. On May 26, 1999 the FERC approved the BFM.

<u>Proposed Bilateral Forward Pilot Program</u>:

On March 30, 1999, Southern California Edison (Edison) filed Application 99-03-022, in which the company requested permission to establish a pilot program for entering into bilateral forward power purchasing agreements for energy and capacity. The quantities purchased would be bid into the PX day-ahead and/or hour-ahead markets, and/or into the ISO's imbalance or ancillary services markets. Edison proposed to limit its purchases under this program to 2000 MW[1]. Edison proposed an incentive mechanism whereby shareholders would share profits and gains resulting from the program.

In advocating forward purchases, Edison argued that they mitigate price spikes and enable the company to compete for lower cost supplies. In advocating bilateral purchases

[1] Edison stated that 2000 MW represented about 10% of the peak summer demand of Edison's full service retail customers.

outside the PX, Edison noted that this program would enable the company to engage in forward purchases in the event the PX's BFM were delayed.

In D.99-07-018, issued on July 8, 1999, the CPUC reiterated its belief in the rationale behind the buy/sell agreement, namely, price transparency, market power mitigation. The CPUC rejected Edison's pilot program application, stating that the proposal would violate the buy/sell agreement. The decision further elaborated:

> The FERC characterized the buy/sell requirement as "critical to the entire retail restructuring proposal."[2] It acted upon the buy/sell requirement "independently."[3] As we recognized in our Preferred Policy Decision, close cooperation and coordination with the FERC is required for our restructuring effort to be successful. We are disinclined to embark upon piecemeal changes to the carefully structured market of the transition period, upon which the FERC predicated its conditional approval of the operation of the ISO and the PX. (p.10)

While rejecting Edison's bilateral purchasing program, the decision favored development of forward purchases:

> The PX application before FERC for approval of its Block Forward Market, granted May 26, 1999, should <u>encourage development of forward markets</u>, and in a manner consistent with our Preferred Policy Decision. We anticipate that the Block Forward Market will help mitigate price spikes as well. (p.12)

<u>IOU involvement with the PX BFM</u>:

On April 19, 1999 Edison filed advice letter 1377-E and on April 22, 1999 Pacific Gas and Electric (PG&E) filed advice letter 1866-E. These advice letters proposed:

- to include the cost of utility power purchases from the BFM in the utilities's Schedule PX tariff, which is used for calculating the PX credit;
- that BFM purchases be deemed prudent *per s*e by the CPUC, as are other PX purchases.

On July 8, 1999 the advice letters were approved with modifications by the CPUC in Resolution E-3618. The resolution stipulated as follows:

- the CPUC's intention was that forward purchases be used for hedging, not speculation;
- proposed advice letter language allowing cost recovery from the BFM "or any other type of forward energy market" was revised to restrict purchasing to only the PX BFM;
- authorization was granted for cost recovery of BFM costs incurred up to October 31, 2000, subject to the outcome of the Post-Transition Ratemaking Proceeding;
- requirements were established for monthly reports to Energy Division regarding BFM activity;

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[2] <u>*Pacific Gas and Electric Company*</u>, 77 FERC ¶ 61,265, 62,089 (1996).
[3] *Id*. 62,088.

- BFM transactions were limited to one third of their historical minimum hourly load. For PG&E that equates to a limit of approximately 2000 MW from July to September. For Edison that equates to between 1800 and 2000 MW.

Following up on the other two utilities' filings, on May 20, 1999 San Diego Gas and Electric (SDG&E) filed advice letter 1167-E. The primary goal of the advice letter was to request that purchases made by from the PX BFM be deemed reasonable *per se*. On July 22, 1999 the CPUC issued Resolution E-3620, which approved the advice letter, with restrictions nearly identical to those imposed on Edison and PG&E in Resolution E-3618.

<u>Expansion of BFM: new PX products, raised volume limits, and extended terms</u>:

On December 30, 1999 the PX filed a tariff modification with the FERC to offer additional BFM products involving new delivery periods (blocks) and new delivery locations. The new "Super Peak Energy" and "Shoulder Peak Energy" were each 6-day by 8-hour blocks, which bifurcated the 6x16 block. The new locations included the California-Oregon border (COB).

On January 6, 2000 Edison filed AL 1429-E, and on January 19, 2000 PG&E filed AL 1960-E. These advice letters requested:

- permission to participate in the proposed new PX BFM products;
- increased volume limits. For PG&E the limit would increase from 2000 to 3000 MW; Edison's limit would increase from between 1800 and 2000 to a range of 2200 to 5200, depending on the month (Edison derived its proposed limit from the "net short" concept[4]);
- extended term of authorization to March 31, 2002.

On March 16, 2000 the CPUC approved the advice letters in Resolution E-3658. The Resolution affirmed that all PX purchases during the rate freeze are deemed reasonable. Any post rate freeze modifications were to be addressed in Phase 2 of the PRT Proceeding. The Resolution set BFM limits at the utilities' net short position, as Edison had requested.

<u>PX BFM Ancillary Services</u>:

On February 17, 2000 the PX applied to the FERC to establish a forward market for five categories of ancillary services (A/S) starting May 1, 2000. This was intended to supplement the ISO's A/S market. Deliveries were to be scheduled through the PX day-ahead market. On April 25, 2000 the FERC approved PX's application.

[4] The net short position is the amount by which the demand of the utility's bundled customers exceeds the supply provided by utility-scheduled resources (e.g., nuclear plants and qualifying facilities) and previously acquired BFM purchases.

On March 21, 2000 Edison filed advice letter 1443-E. On March 30, 2000 PG&E filed advice letter 1986-E. These advice letters requested authorization to participate in and recover costs from participating in this new PX market.

The CPUC approved these new activities in Resolutions E-3666 (May 4, 2000, for Edison) and E-3672 (June 8, 2000, for PG&E). Volume limits were set for these purchasing activities.[5]

PX BFM Authorization for Daily and Balance-of-the-Month Contracts:

On May 2, 2000 the PX filed tariff amendments and rate schedule revisions to allow CTS participants to trade energy on a daily basis and on a balance-of-the-month block forward basis. On June 23, 2000 the FERC approved the filing.

On May 17, 2000 Edison filed advice letter 1453-E requesting authorization to participate in and recover costs associated with these new PX products. Edison also requested expanded trading limits[6], an extension of the term through the end of the rate freeze, and permission to take advantage, with prima facie reasonableness determination, of new products and new locations offered by the PX in the future.

On May 19, 2000 PG&E filed advice letter 2003-E requesting similar authorization regarding the new PX products, including a higher limit.

In Resolution E-3683 the CPUC approved the two advice letters, with modifications. The monthly BFM limit was not increased, but a combined limit for the monthly, daily, and balance-of-the-month BFM participation on any one day was set at each utility's quarterly net short position (as described in Resolution E-3658) plus 1,000 MW. The Commission's explained its rationale in the following way:

> The primary reason for limiting BFM participation is to protect ratepayers from the risk of over-procurement. Limiting BFM participation also reduces opportunities for speculation and the exercise of market power. Conversely, the primary reason for increasing the limit in BFM participation is to allow utilities to hedge against known contingencies and increases in demand that could result in price spikes. Our task is to balance these competing concerns. (p.6)

In the resolution, the Commission granted authority to trade at the new locations requested (Mead, Palo Verde, and COB), but denied automatic future approval for any new PX products.

PX BFM Authorization for SDG&E:

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[5] Edison's participation in the A/S forward market was limited to 1550 MW, 1600 MW, 1625 MW, and 1575 MW in any hour of the 1st, 2nd, 3rd, and 4th quarters, resptecively. PG&E's participation in the A/S forward market was limited to 475 MW, 525 MW, 600 MW, and 500 MW in any hour for the 1st, 2nd, 3rd, and 4th quarters, respectively.

[6] Edison asked that the limit for the daily and balance-of-the-month forward purchases be 1,000 MW (the size of Edison's largest generation unit) above the net short position.

On July 10, 2000 SDG&E filed advice letter 1234-E, requesting CPUC permission to expand the number of PX BFM products in which the utility was allowed to participate. The expanded product list would include:

- the monthly and quarterly forward energy markets;
- the daily and balance-of-the-month markets;
- ancillary services, both monthly and quarterly;
- new delivery points; and
- new delivery periods.

On July 19, 2000 a supplemental advice letter filing 1234-E-A requested limiting the BFM program to residential and small commercial customers, arguing that these customers more than others needed rate certainty and would be willing to pay the increased average cost this could entail.

In its August 3, 2000 meeting the CPUC issued Decision 00-08-021. Among many other directives, the Commission approved those advice letters but did not allow the BFM program to be limited to certain customer groups.

Expanding Beyond the PX:

On June 8, 2000 the CPUC issued Decision 00-06-034, also known as the Phase 2 decision in the Post-Transition Ratemaking proceeding. Among other directives, the decision expanded the allowable field of utility power purchases to "any qualified exchange during the transition period".

Following the PRT decision, the California Legislature modified the PU Code, effectively negating part of the PRT decision. Section 355.1 reads:

> Prior to June 1, 2001, the commission may not implement the part of any decision authorizing electrical corporations to purchase from exchanges other than the Power Exchange. That portion of any decision of the commission adopted prior to January 1, 2001, but after June 1, 2000, authorizing electrical corporations to purchase from multiple qualified exchanges, may not be implemented.

On July 21, 2000 PG&E and Edison each filed emergency motions seeking authorization to enter into bilateral power contracts for power, capacity, and ancillary services. The utilities cited the need to better hedge against high spot prices, and to introduce new supply into California. While the deals would be made outside of the PX BFM market, power thus procured would be scheduled via the CTS in the PX day-ahead market.

No increase in capacity limits from previously established levels was requested. However, the utilities did request term extensions – for PG&E, to the end of calendar year 1993, and for Edison to the end of calendar 1995.

Both companies requested reasonableness determination procedures. PG&E requested that ORA and Energy Division be consulted in pre-establishing a "window" of reasonable prices. If PG&E purchases were inside this window, they would be deemed reasonable per se. Edison envisioned "short term" (those with all deliveries occurring before the end of 1992) and "medium-term" (those including deliveries after 12-31-02) contracts. For its short-term contracts, Edison proposed that an *ex post* reasonableness review be triggered only if the prices paid under the bilateral contracts exceeded by more than 20 % the rest of the PX portfolio. For its medium term contracts, Edison proposed that Energy Division be consulted prior to purchasing, thereby receiving the imprimatur of reasonableness.

On August 3, 2000 the CPUC, in Decision 00-08-023, approved both emergency motions, with some modifications. The Commission reasoned that the decision did not violate PU Code 355.1, since bilateral deals were not conducted in any exchange *per s*e. Both utilities were allowed to enter into bilateral deals with terms extending through the end of 2005. Edison's dead band for reasonableness reviews was shrunk from 20 to 5%. The utilities were ordered to file monthly reports with Energy Division.

On August 9, 2000 SDG&E filed an emergency motion requesting bilateral purchasing authorization similar to what had been granted Edison and PG&E. On September 21, 2000 the CPUC, in Decision 00-09-075, granted SDG&E's motion, with key modifications concerning reasonableness treatment. SDG&E was not granted a procedure for *ex ante* reasonableness determination, but instead will face an after-the-fact reasonableness review.

Practical Effects of Volume Limits:

As noted above, the CPUC's rationale for setting forward purchase limits at the utility's net forward position is to provide the utilities the opportunity to hedge against high spot prices, while preventing them from engaging in speculation that could be financially risky for ratepayers.

The FERC order has stated that CPUC rules require about 80% of utility load to be obtained from the day-ahead and day-of markets. Further, the FERC order suggests that ratepayer interests would be better served if procurement limits on forward products were raised.

And yet, the experience of the last 18 months (since the forward market was first offered by the PX) shows that while Edison and PG&E have generally benefited from forward purchases, they have not come close to using up their procurement allotments[7]. A closer look at procurement volumes and limits should help to explain some of the confusion.

As an example, PG&E in the month of June 2000 had a total bundled energy requirement of 6,635,939 MWh. Resources owned by PG&E (mostly hydro and nuclear, with some contribution from gas and oil plants) contributed 2,841,848 MWh. Qualifying facilities (QFs) contributed 1,861,870 MWh. Both the PG&E resources and the QFs are must-

[7] Edison has used about 59% of its allotment, while PG&E has used about 33%.

take resources and are bid into the PX at a price of zero. PG&E also procured 1,932,221 MWh above its must-take level.

It should be made clear that the prices at which must-take resources clear the market have no effect on ratepayers, since ratepayers are paying <u>and</u> receiving these prices. It is only the price of power procured <u>above</u> the level of must-take resources that affects ratepayers.

PG&E's forward purchasing limit for June is 2,400 MW. There are 416 peak hours (6 days a week, 16 hours a day) in June. If PG&E had bought 100% of its allotment for peak power, it would have procured (2,400 x 416 =) 998,400 MWh of forward power. This is over 50% of the amount of power requirement beyond the must-take level (which is 1,923,221 MWh). In other words, if PG&E had procured its allotment of forward power for that month (in actuality, PG&E purchased 47% of its allotment), less than half of the amount of power whose price affects ratepayers would have been purchased from the day-ahead or day-of markets.

The largest reason why forward purchases do not come closer to covering all of the power requirements beyond must-take levels is that the utilities have not requested permission to procure monthly blocks of 7 x 24 forward energy. Currently they are constrained to peak hours. With 7 x 24 blocks in addition to 6 x 16 blocks, the utilities should, on average, be able to <u>entirely</u> avoid the spot market if they choose to do so.

Volume Limits for Forward Power Purchases

	Description and Criteria	Edison	PG&E	SDG&E
Resolution E-3618 July 8, 1999 Response to: Edison AL 1377-E PG&E AL 1866-E	PX BFM. Peak energy (6x16). One third of the historical minimum hourly load by month.	Between 1800 and 2000 MW. (this amount was stated later in Edison's AL 1429-E)	Approximately 2000 MW in months July-Sept. (this amount was stated later in PG&E's AL 1960-E)	Not Applicable
Resolution E-3620 July 22, 1999 Response to: SDG&E AL	PX BFM. Peak energy (6x16). One third of the historical minimum hourly load by month.	N/A	N/A	400 MW
Resolution E-3658 March 16, 2000 Response to: Edison AL 1429-E PG&E AL 1960-E	PX BFM. Peak energy (6x16). Net short position by quarter: for each hour the net short position is the amount by which the demand of bundled customers exceed the IOU-controlled supply (e.g., QFs, nukes), excluding previously existing BFM purchases. The numbers adopted reflect the quarterly average of the hourly figures.	1st Quarter: 2200 MW 2nd Quarter: 2200 MW 3rd Quarter: 5200 MW 4th Quarter: 3000 MW	1st Quarter: 2900 MW 2nd Quarter: 2400 MW 3rd Quarter: 4340 MW 4th Quarter: 4000MW (these amounts were provided in 8-24-00 presentation by PG&E to Energy Division; however, in response to data request of June 29, 2000 PG&E provided: 1st Quarter: 4272 MW 2nd Quarter: 3855 MW 3rd Quarter: 4883 MW 4th Quarter: 5400 MW; awaiting clarification)	N/A
Resolution E-3666 May 4, 2000 Response to Edison AL 1443-E Resolution E-3672 June 8, 2000 Response to PG&E AL 1986-E	Five kinds of Ancillary Services from the PX BFM.	1st Quarter: 1550 MW 2nd Quarter: 1600 MW 3rd Quarter: 1625 MW 4th Quarter: 1575 MW These levels reflect Edison's historical A/S obligations.	1st Quarter: 475 MW 2nd Quarter: 525 MW 3rd Quarter: 600 MW 4th Quarter: 500 MW A/S purchases are limited to 5% of historical hourly demand averaged over a given quarter.	N/A
Resolution E-3683 July 6, 2000 Response to: Edison AL 1453-E PG&E AL 2003-E	Daily forward contracts and balance-of-the-month forward contracts offered by the PX BFM. Level above BFM monthly level set at capacity of largest generator (1000 MW).	The monthly BFM limit was not increased, but a combined limit for the monthly, daily, and balance-of-the-month BFM participation on any given day was set at each utility's quarterly net short position plus 1000 MW.	Same as Edison	N/A
Decision 00-08-081 August 9, 2000 Response to: SDG&E AL 1234-E SDG&E AL 1234-E-A	Approves limits proposed by SDG&E for A/S and various energy products available from the PX BFM. Monthly limits based on 90% of average min and max bundled peak (6x16) load for May 1999 to April 2000.	N/A	N/A	Forward monthly energy limits: 1900 MW for Q3; 1700 MW for Q1, Q2, and Q4. Sum of daily, balance-of-month and monthly energy not to exceed monthly energy limits by more than 1000 MW. A/S forward purchases will not exceed 90 % of forecast of A/S.

Exhibit PUC-12
Utility use of Forward Markets and Hedging Instruments

In the past 18 months Southern California Edison (Edison) and Pacific Gas and Electric (PG&E) have used the California Power Exchange (PX) Block Forward Market (BFM) hedging tools available to them to great effect, very likely[1] avoiding hundreds of millions of dollars in energy procurement expenses. Estimated savings for Edison are $513 million and for PG&E are $203 million. Over the course of the PX BFM program, Edison has procured approximately 59% of its allowed hedging allotment, while PG&E has procured approximately 33% of its allowed hedging allotment. The CPUC has not determined whether more economical forward contracts were available, or whether these two utilities should have procured additional forward resources.

SDG&E also has had authorization to procure forward power but has not availed itself of the opportunity.

As described in Exhibit 16, the utilities are authorized to procure forward contracts from the (PX). Almost all of the hedging activity has involved contracts for monthly forward energy.

Pursuant to CPUC decisions in August and September of 2000, the three utilities have been granted permission to procure forward energy and capacity outside of the PX. All three companies sent out requests for bids and in October 2000 PG&E signed forward contracts.

[1] Edison has asserted that the calculations made to determine savings arising from procuring forward power are meaningless since there is no way to know what the price of PX power would have been had there been no forward purchases.

Monthly PX BFM Contracts

	Edison				PG&E				SDG&E			
	Forward Energy Allowed	Forward Energy Procured	Percentage of Limit Used	Estimated Savings	Forward Energy Allowed	Forward Energy Procured	Percentage of Limit Used	Estimated Savings (Losses)	Forward Energy Allowed	Forward Energy Procured	Percentage of Limit Used	Estimated Savings
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(12)
	MW	MW	%	$1,000	MW	MW	%	$1,000	MW	MW	%	$1,000
Aug-99	1900	1175	62%	(4,449)	2000	725	36%	(2,257)	400	100	25%	(48)
Sep-99	1900	1850	97%	(3,546)	2000	1325	66%	2,084	400	100	25%	(169)
Oct-99	1900	1150	61%	25,062	2000	0	0%	0	400	0	0%	0
Nov-99	1900	0	0%	0	2000	1125	56%	2,591	400	0	0%	0
Dec-99	1900	700	37%	(59)	2000	1475	74%	3,801	400	0	0%	0
Jan-00	1900	550	29%	1,010	2000	925	46%	22	400	0	0%	0
Feb-00	1900	975	51%	775	2000	0	0%	0	400	0	0%	0
Mar-00	1900	1500	79%	774	2000	500	25%	(289)	400	0	0%	0
Apr-00	2200	1325	60%	1,161	2400	525	22%	(421)	400	0	0%	0
May-00	2200	1425	65%	20,635	2400	500	21%	5,504	400	0	0%	0
Jun-00	2200	1875	85%	103,461	2400	1125	47%	64,426	400	0	0%	0
Jul-00	5200	3375	65%	102,899	4340	1775	41%	20,203	1900	0	0%	0
Aug-00	5200	3050	59%	184,585	4340	1875	43%	73,282	1900	0	0%	0
Sep-00	5200	3050	59%	80,724	4340	1925	44%	34,831	1900	0	0%	0
Totals			59%	513,032			33%	203,777			2%	(217)

(2),(6),(10) See Exhibit 16-A for Commission orders setting limits.

(5),(9),(13) Savings are calculated as the difference between the actual amount paid for BFM contracts, plus volumetric fees, and the product of the PX price times the volume of BFM acquired. Edison contends that this calculation does not accurately represent savings, since the PX price for the month in question would have been different if no BFM purchases had been made.

BFM purchases in ancillary services and daily and balance-of-the-month blocks are relatively very small.

(6) PG&E's numerical limits are being verified

(10) SDG&E's actual numerical limits never cited in Commission filed documents; estimate is from Mr. Bill Reed of Sempra (p.265 of transcript of August 24 hearing in San Diego in O.I.I.00-08-002 docket).